Citation	Juliana Zapata Riveros, juliana.zapata@mech.kuleuven.be Jeroen Vandewalle, jeroen.vandewalle@mech.kuleuven.be William D'haeseleer, william.dhaeseleer@mech.kuleuven.be Title Reducing imbalances with virtual power plant operation
Archived version	Author manuscript: the content is identical to the content of the published paper, but without the final typesetting by the publisher Final publisher's version / pdf
Author contact	william.dhaeseleer@mech.kuleuven.be
IR	url in Lirias https://lirias.kuleuven.be/handle/123456789/u0075836

(article begins on next page)

REDUCING IMBALANCES WITH VIRTUAL POWER PLANT OPERATION

J. Zapata[a,b], J. Vandewalle [a,b], and W. D'haeseleer [a,b*]

[a] University of Leuven (KU Leuven) Energy Institute, TME Branch,

Celestijnenlaan 300A P.O Box 2421,B-3001 Heverlee, Belgium

[b] Energyville (joint venture of VITO NV and KULeuven), Dennenstraat 7,

3600 Genk

*corresponding author: William.Dhaeseleer@mech.kuleuven.be

1 ABSTRACT

The penetration of a large amount of distributed generation technologies with intermittent output, such as photovoltaic installations and wind turbines, yields an important challenge to the electric grid.

This work illustrates the case of a virtual power plant that consists of several Cogeneration devices (CHP) systems and photovoltaic (PV) installations. The virtual power plant (VPP) operator bids electricity to the day-ahead market using the forecast for solar irradiation. In real time, the imbalance due to deviations between the forecast delivered and the real output has to be settled in the balancing market. Thus, in order to compensate for these errors, the operation of the CHP is rescheduled.

The results show that the reduction of the imbalance can be larger than 80% depending on the season. Additionally, the total operational cost is estimated. It is shown that in most of the cases the increase of the fuel cost is compensated by the reduction of the imbalance cost.

Finally, it is demonstrated that the heat demand largely limits the ability of the CHP to reduce imbalance particular in summer

Keywords: cogeneration, balancing market, photovoltaics, optimization.

2 introduction

The large penetration of distributed generation (DG) in the electric grid yields several challenges to the operation of the system. Several DG technologies have an intermittent output that is very difficult to forecast (i.e. wind and solar). This adds considerable uncertainty to the electricity system.

In order to counterbalance this unpredictability, it is proposed to aggregate different distributed generation technologies in what is known as a virtual power plant. Due to the characteristically low generation capacity of DG, a VPP will also enable their participation in the wholesale market

The operation of a day-ahead market (DAM) can be explained as follows: On the day before actual electricity delivery, the market participants bid into the market. Based on the submitted bids the market determines the clearing price.[1] The bids that have prices lower than the clearing price are accepted in the market.

In principle, the prices are based, amongst other factors, on the variable operation and maintenance cost of the generation facility. Since photovoltaic (PV) and wind energy have minimal fuel cost, their bids are generally granted. The low predictability of these technologies increases the cost to compensate the imbalance between injection and off-take of the electric power.

The impact of distributed generation in the Dutch balancing market has been studied in [1]. The conclusions show that large penetration of PV in the electricity grid can jeopardize the performance of the balancing market. On the other hand, large penetration of micro-cogeneration (micro-CHP) can produce positive effects depending on the employed control strategy.

The ability to reduce imbalance by making use of a VPP has been explored in several works. In [2] it was proven that a VPP conformed by a group of CHP plants can comply with a predefined schedule even under deviations between the forecasted and actual load. This, however, compromises the ability to obtain maximum profits since part of the production and storage capacity has to be reserved to overcome deviation.

Furthermore, in [3], the imbalance minimization is studied for a VPP composed of biomass, wind, PV generators and a flexible freezer demand of a supermarket. It is concluded that using the flexible demand the imbalance decreases although the economic incentive is low.

[1] Clearing price or Marginal price is the price of the last MWh of electric energy that is needed that day

Additionally, in [4], a VPP that consist of a wind farm, a solar installation and a conventional gas turbine is simulated. The VPP has a long term bilateral contract and the gas turbine should help to cover the deviations of the contract. Nevertheless, it is found that it is better to cover these deviations buying the electricity from the day-ahead market than using the gas turbine.

Finally, [5] assesses the possibility to balance a large scale PV installation making use of an industrial CHP unit. The study calculates the maximal reduction of imbalance cost by assuming that the forecasting errors on the analyzed horizon are well known. The results predict a possible imbalance reduction of more than 80%. However, this work does not take into account the impact on the operational cost. Additionally, since the imbalance pricing mechanism in Belgium changed at the beginning of 2012 the study is out of date.

In this study, the possibility to reduce the imbalance of a VPP that consist of several micro-CHP devices and PV installations is analyzed. This work focuses on the reduction of the physical imbalance and the consequent decrease of the cost due to the avoided payment for balancing payment.

Other situations such as trying to take advantageous positions on the intra-day market are not taken into account. This is due to the fact that nowadays this market in Belgium has low liquidity.

The optimization algorithm reschedules the output of the micro-CHPs every time step depending on the real PV output. The results include not only the impact on the imbalance price but also the total operational cost.

Furthermore, this works studies how the heat demand can limit the ability of the CHP to reduce the imbalance.

The following section describes the methodology applied, it explains the optimization algorithm and the assumptions employed additionally, it depicts the operation of the balancing market in Belgium. Afterwards, the results are presented and analyzed. To finalize, conclusions are stated.

3 method

3.1 Problem description

The present study considers a virtual power plant that consists of several micro-CHP devices and PV installations. The electricity generated by micro-CHP will be mainly used to meet the electric demand of the VPP. On the other hand, the PV electricity will be sold on the DAM. Thus, it is assumed that, using a prediction of the solar irradiation, the VPP operator will bid a certain amount of electricity in the market.

In real time, if the VPP fails to deliver the contracted electricity, the difference should be settled in the balancing market. For this reason, every time step the CHP production should be rescheduled in order to reduce the imbalance.

The rescheduling strategy is performed using a mixed integer linear programming model that is solved by the optimization software CPLEX. In order to simplify the optimization problem only a number of participants of the VPP are studied, this includes: three multifamily houses each of them with a micro-CHP system (CHP prime mover, boiler and storage tank) and several PV installations with maximum output amounts to 32kW.There is no heat connection between the houses. However, the electricity generated by the CHP can be used to meet the common electric demand.

It is assumed that the virtual power plant is a balance responsible party (BRP) and thus is responsible for the imbalance in its perimeter. Therefore, the objective of the optimization is to reduce the total imbalance cost.

The optimization was performed for two consecutive days typical of the three different seasons (summer, intermediate and winter). The imbalance reduction and the economic advantages are compared among the different seasons and with respect to the case where the CHP operation is not rescheduled.

Finally the impact of the heat demand on the potential of the CHP to reduce the imbalance is assessed.

3.2 Optimization

Two different optimization algorithms are employed: the first optimization is performed the day ahead, with the objective to find an operational schedule for the CHP and boiler that minimize the energy cost of the household.

It is assumed that large part of the electricity generated by the CHP is going to be used to meet the local demand; this is due to the fact that the DAM prices are most of the time not large enough to motivate the use of the CHP for selling electricity into the grid. Nevertheless, the system allows feed excess of electricity in the grid and thus this part of the optimization also gives the amount of electricity produced by the CHP that is going to be sold in the DAM.

The second optimization aims to reduce the imbalance due to the forecast errors. This part is implemented in a rolling horizon approach. First, the actual real-time PV output is obtained. Then, the simulation is performed every time step making use of the actual and forecasted PV outputs. Afterwards, only the first step of the simulation is implemented and the procedure is repeated during the next period. Both the cost and balance optimization algorithms are explained in detail in the following.

First optimization algorithm (Cost minimization)

As already mentioned, the objective of the cost optimization algorithm is to minimize the operational cost of the system as expressed in equation (1) and extended in equation (2). The operational cost is the sum of the fuel cost of the CHPs and boilers (C_{CHP}, C_{boiler}).On the other hand, the savings include the revenues due to the electricity that is sold to the grid (G_{grid}) and the savings due to the self-consumption of the electricity generated by the CHP (G_{local}):

$$\min objective\ function = \sum_{t=1}^{T} (Cost(t) - Savings(t)) \qquad (1)$$

$$min = \sum_{t=1}^{T} \left(C_{CHP}(t) + C_{boiler}(t) - G_{local}(t) - G_{grid}(t)\right) \qquad (2)$$

The optimization is constrained by several operational and technical conditions. The operational constraints ensure that the heat demand (Q_{demand}) will always be met using the CHP (Q_{chp}), the boiler (Q_{boiler}) or the heat that is (dis)charged from the storage (Q_c). As described in equation (3):.

$$Q_{demand}(t) = Q_{chp}(t) + Q_{boiler}(t) + Q_c(t) \qquad (3)$$

The state of charge of the storage tank (q_{st}) is calculated using equation (4). The efficiency of the storage tank (η_{st})[2] is assumed to be constant. The analyzed time step (Δt) is 15 minutes:

$$q_{st}(t) = (\eta_{st}) * q_{st}(t-1) - Q_c * \Delta t \qquad (4)$$

The electricity generated by the CHP (E_{chp}) can be used inside the VPP (E_{local}) or sold to the electricity market (E_{grid}):

$$E_{CHP}\,(t) = E_{local}\,(t) + E_{grid}(t) \qquad (5)$$

[2] The efficiency of the storage tank represents the percentage of heat that remains in the storage after it has been stored during one time step.

On the other hand, some technical restrictions prevent to exceed the operational limits of the machines. This is expressed in equations (6)-(9) for the storage, the boiler and the CHP respectively:

$$0 \leq q_{st}(t) \leq q_{st\_max} \qquad (6)$$

$$0 \leq Q_{boiler}(t) \leq Q_{boiler\_max} \qquad (7)$$

$$Q_{chp\_min} \leq Q_{chp}(t) \leq Q_{chp\_max} \qquad (8)$$

$$E_{chp\_min} \leq E_{chp}(t) \leq E_{chp\_max} \qquad (9)$$

3.3 Other technical constraints control the minimum start up time of the CHP device. This is performed as in [6] and it is important to consider in order to avoid wearing out of the machine.

As no heat connection exist between the houses, each system has to satisfy its individual heat demand; thus, equations (3)-(4) and (6)-(9) apply to every individual CHP. On the contrary, the electric demand is the aggregated electric demand of the houses. Therefore, the electricity generated by the CHP (E_{chp}) is equal to the individual production of each CHP device:

$$E_{CHP}(t) = E_{\mathrm{CHP1}}(t) + E_{CHP2}(t) + E_{CHP3}(t) \qquad (10)$$

Second optimization algorithm (Imbalance reduction)

The objective function of the second optimization problem is to minimize the imbalance error. As stated in equation (11), this is the difference between the real output (Out_{real}) and the forecasted output ($Out_{forecast}$). This optimization is performed every time step once the real PV output is obtained.

$$min = \sum_{t=1}^{T} |Out_{Real}(t) - Out_{Forecast}(t)| \qquad (11)$$

Although the objective function is different, the optimization has the same constraints previously explained and described in equations (2)-(10). Nevertheless, an additional constraint guaranties that the imbalance is always covered either by the actual CHP output (E_{CHP_Real}) or getting the electricity from the balancing market (E_{Imb}) as expressed in (12). The variable E_{Imb} can be positive or negative depending on the nature of the imbalance error.

$$Out_{forecast}(t) = Out_{Real}(t) + E_{CHP\_real}(t) + E_{Imb}(t) \qquad (12)$$

3.4 Assumptions

3.5 Cogeneration system

The cogeneration system consists of a prime mover, a thermal buffer and an auxiliary boiler. The prime mover was sized for each house using the maximum rectangle method as explained in [7]. It is assumed that all cogeneration devices are able to modulate and the modulation characteristics are similar to the commercial CHP device Ecopower plus that are explained in [8] and measured by [9].

The capacity of the storage tank is calculated in such a way that the buffer is able to store two hours of the maximum thermal output produced by the CHP during one hour. This was proven to be an optimal size for the tank [8][10]. It is assumed that the storage tank starts and ends empty.

Finally, the auxiliary boiler covers the remaining heat demand. The boiler efficiency is assumed to be constant and equal to 90%.

3.6 Photovoltaic forecasted and measured data

The PV profile used was measured at a fixed rooftop PV installation at the KU Leuven Campus in Belgium. The data is available in fifteen minutes time steps. The profile was rescaled for each house to cover 100% of the annual electricity demand of the dwelling [11].

In order to obtain a reasonable forecast the measured values were averaged for an hour and randomized using a normal distribution with a standard deviation of 0.2. Figure 1 illustrates the real and forecasted PV output.

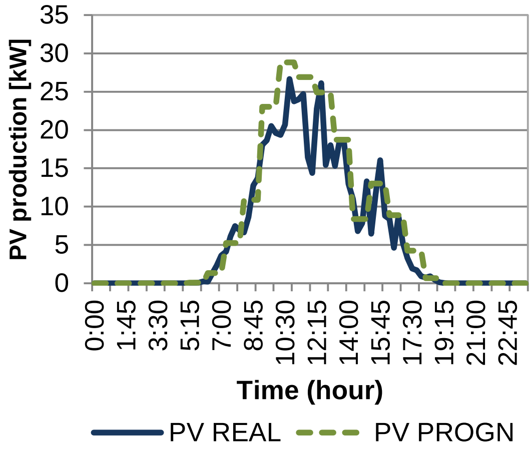


Figure 1 The green dashed line represent the prognosed Pvoutput; the blue line corresponds to the real PV output.

Electricity and gas prices

For the present work it is assumed that the price for the local electricity corresponds to the residential tariff which amount to 0.15 €/kWh at night and 0.22 €/kWh during the day.
With regard to the DAM price, the values are obtained from the BELPEX[3] internet platform and correspond to the year 2012.
It is also assumed that, the VPP will pay a gas price equal to the price that is paid by small and medium sized enterprises which in the case of Belgium is equivalent to 0.039 €/kWh[4].

The imbalance prices are publicly available at the internet page of ELIA[5]. The working mechanisms of the Belgian balance market are explained in the next section.

[3] BELPEX is the Belgian Power Exchange for anonymous, cleared trading in day-ahead electricity.
[4] Since the structure of the market for a VPP is not yet clearly stablished the model employs both retail and whole sale market prices. In the future the regulator should clarify the rules for the market.
[5] ELIA is the Belgian transmission system operator (TSO) for electricity

3.7 Belgian balance market

The Belgian transmission system operator for electricity, ELIA, is responsible for ensuring the balance between the generation and consumption inside the country [12].

This duty is shared with the different balance responsible parties (BRP) which are responsible for maintaining the balancing of their own portfolio. The BRPs are charged for any imbalance that occurs in the perimeter. The imbalance prices are designed to encourage the BRPs to maintain the balance in their perimeter.

Since January 2012, the Belgian imbalance pricing consist of a single price for both up and down regulation with an additional incentive mechanisms α and β that are activated only in case of large imbalance.

The imbalance bill that the BRP has to pay consists of the volume fee and the imbalance charge. The volume fee accounts mainly for the administrative cost.

The imbalance tariffs are estimated taking into account several factors such as:

- The nature of the imbalance (The imbalance is positive when the BRP injects extra energy to the system and negative in the contrary case (off-takes>injection)).
- The cost of the activation
- The position of the Belgian control area

The concept of the imbalance mechanisms is simplified in Table 1. In general four different cases can occur as shown in the table (A,B,C,D).

In cases B and C the position of the BPR helps to reduce the general imbalance. Thus, in case B the TSO pays to the BRP the Marginal Incremental Price (MIP). Alternatively, in case C the BRP pays to Elia the marginal price for down regulation or marginal decremental price (MDP).

On the contrary, in cases A and D the BPR position aggravates the total imbalance thus it will receive the MDP or pay the MIP in case of positive or negative imbalance respectively.

As mentioned before α and β are only active if the total system imbalance is larger than 140 MW.

Table 1 Belgian balancing pricing [12]

<table>
<tr><td colspan="2" rowspan="2"></td><td colspan="2">Situation of ELIA</td></tr>
<tr><td>Surplus</td><td>Deficit</td></tr>
<tr><td rowspan="4">Imbalance in the BRP</td><td rowspan="2">POSITIVE</td><td>A</td><td>B</td></tr>
<tr><td>MDP-α1</td><td>MIP-β1</td></tr>
<tr><td rowspan="2">NEGATIVE</td><td>C</td><td>D</td></tr>
<tr><td>MDP-β1</td><td>MIP+α2</td></tr>
</table>

The average price for negative imbalance for the last 10 months (January to October 2012) was 5.027 c€/kWh and for positive imbalance was 5.241 c€/kWh. This market nevertheless is very volatile and can reach larger values as demonstrated in Figure 2. This figure illustrate an example of the imbalance prices for the 10th of April of 2012 when the prices where larger than the average[12].

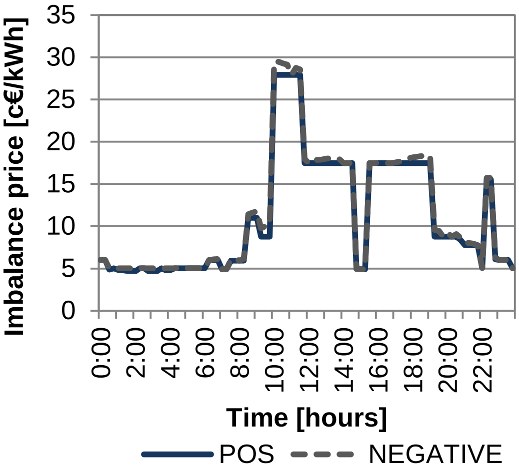


Figure 2 Example of imbalance tariffs for the 10th of april of 2012 [12].

4 Discussion and results

As stated before, two consecutive days of each season (winter, summer and intermediate) were chosen to perform the simulations. Additionally, two different scenarios are considered. In the reference scenario, the operation of the CHP is planned the day-before the delivery and it is not adjusted afterwards.

In the second scenario, the CHP operation is rescheduled in real time in order to reduce the imbalance due to the PV forecast.

Figure 3 illustrates the results on a typical spring day[6].The left side of the figure corresponds to the reference scenario, whereas the right side represents the rescheduling approach.

[6] The calculations were performed for two days, the figures show only one day to facilitate the visualization.

In both figures, the black line indicates the amount of electricity that was bid on the market while, the colored area represents the real electric power that was delivered. Looking at the figures it is clear that using the reschedule technique the imbalance can be largely reduced (blue area).

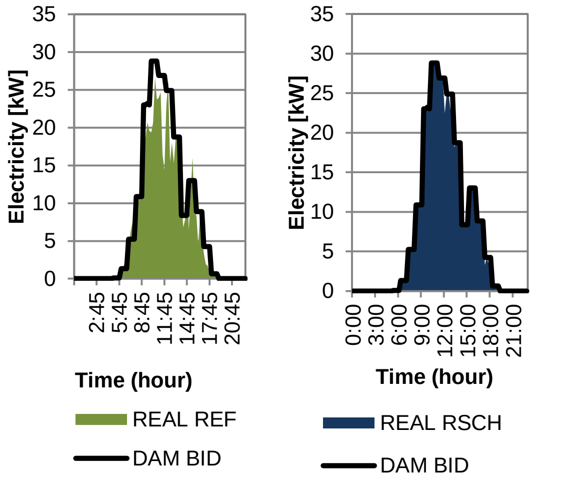


Figure 3 Reference and rescheduled scenarios on a spring day. In the reschedule scenario (right panel) the actual eletricity delivered (blue area) follows more closely the bid (black line.)

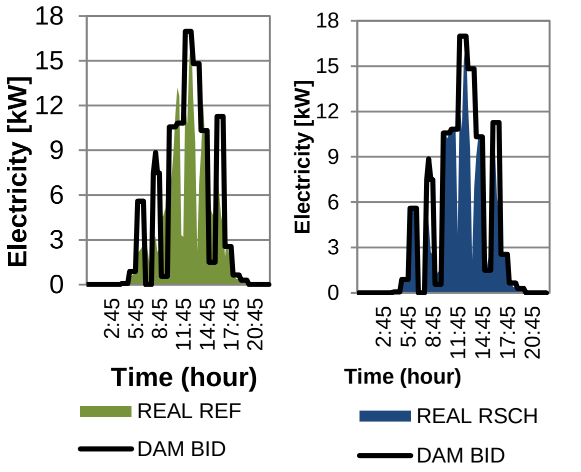


Figure 4 Reference and rescheduled scenarios on a summer day.

In the same way, Figure 4 illustrates the studied scenarios on a summer day. In this case, though the rescheduling of the CHP shows better effects with respect to imbalance, the results are not as good as in the analyzed spring case.

In a further step, the imbalance reduction is calculated with respect to the reference scenario. Table 2 summarizes the results. From the table, it is clear that during winter and the intermediate season, the achieved imbalance reduction is large (more than 80% in all the cases).

However, in summer though the reduction is significant, it is lower in comparison with the other seasons. The reasons will be analyzed in the next subsection.

Table 2 Imbalance reduction with respect to the reference scenario.

SEASON	IMBALANCE REDUCTION	
	POS	NEG
Winter	98%	87%
Summer	64%	27.3%
Intermediate	89%	70%

Afterwards, the total operational cost is estimated. This cost includes the fuel cost of the CHP and the auxiliary boiler and the imbalance cost.

In Figure 5 the cost difference between the reference and the rescheduled scenario is illustrated. The three cost components are included (fuel cost for the boiler and CHP and imbalance cost). In the graph a positive amount indicates an increase of the cost and a negative amount a decrease.

It is clear that with the rescheduling, the CHP is forced to produce more energy in order to compensate the amount that the PV installation fails to provide, thus the cost of the CHP increases consequently, the cost of the boiler decreases since the CHP is simultaneously generating more heat[7]. Furthermore, a decrease on the imbalance price is shown also in all the seasons.

[7] The contrary situation can also appear when the forecasted PV energy is lower than the delivered one and thus the CHP operation is limited increasing the use of the boiler to meet the heat demand.

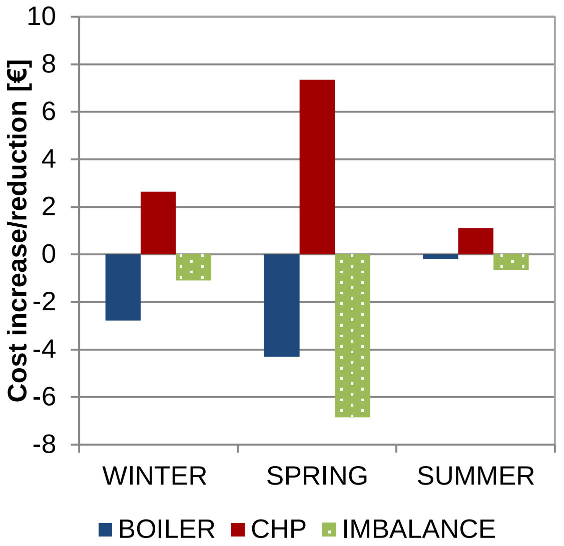


Figure 5 cost reduction with respect to the reference scenario.

Table 3 shows the total cost for the two scenarios and the reduction in percentage value. The largest cost reduction is found during the intermediate season. This is due to the fact that during those two days the imbalance price reached larger values, above the normal average (see Figure 2).

As the imbalance prices for each day differ sharply the comparison of the cost reduction among seasons is not a good indicator of the performance of the optimization and it is better to focus on the imbalance reduction. However, the reduction on the imbalance price gives an indication on how volatile the imbalance market is and thus gives a motivation to reduce the exposure to this market.

On the other hand, in summer instead of a total reduction, there is a small increase of the cost since the decrease on the imbalance prices is not large enough to compensate the increase of the fuel cost of the CHP. This indicates that performing a reschedule is not always profitable for the VPP.

Table 3 Cost difference with respect to the reference scenario.

	REFERENCE	RESCHEDULE	
	COST(€)	COST(€)	REDUCTION
Winter	139.36	138.2	0.89%
Summer	27.7	28	-0.92%
Intermed	60.9	57.13	6.24%

Influence of the heat demand

In Table 2, it was stated that the total imbalance reduction was the lowest in summer. It is well known that the largest amount of PV energy is expected in this season. Thus, it is particularly important to analyze the reasons for this fact.

Contrary to the winter and spring days, the summer season has a characteristically low heat demand. Thus in this subsection was analyzed how the heat demand limits the capacity of the CHP to reduce the imbalance.

As explained in equation (3) the previous simulations were constrained to meet the heat demand all the times. Now, the rescheduling is performed giving a lower and upper margin of 5% to the heat demand. In other words, the heat provided by the CHP, boiler or storage tank can be 5% more or less than the actual heat demanded by the house.

This will give an insight in the way how the heat demand restricts the potential of the CHP to minimize the imbalances.

The results corresponding to the sum of the heat demand among the houses are shown in Figure 6. The upper figure (a) shows in red the heat demand in a winter day, with a maximum peak in the morning and a small peak in the evening. The blue line represents the heat demand of a typical summer day, which has an irregular pattern. Figure (b) gives a closer look to the summer case.

The gray area limited by the black lines corresponds to the given heat demand margin. The red lines on the other hand represent the actual heat delivered to the house.

It can be observed that in summer the upper limit is reached several times. On the contrary, in winter the heat delivered remains on the lower limit.

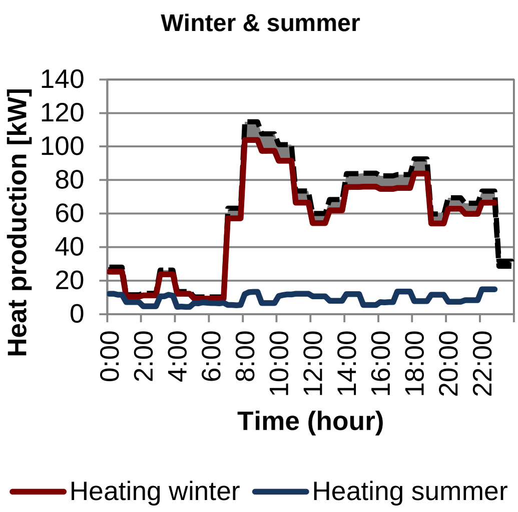
The imbalance reduction for the different seasons with the 5% margin is depicted in Table 4. Comparing with Table 2, it is clear that in summer the total imbalance reduction increases. Both Figure 6 and Table 5 give a clear indication that the lower heat demand limits the capacity of the CHP to respond to imbalance and this can be very critical in summer.

Table 4 Imbalance reduction with 5% margin on the heat demand

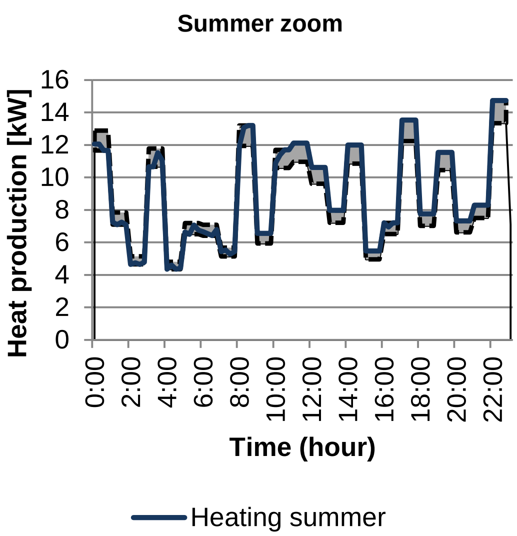
SEASON	IMBALANCE REDUCTION WITH 5% MARGIN	
	POS	NEG

Winter	98.7%	87%
Summer	68%	42%
Intermediate	87%	71%

In order to reduce the influence of the heat demand during the summer months the capacity of the storage could be enlarged. Nevertheless, in [8] it was demonstrated that this measure has a negligible impact on the yearly production of the CHP and that selected size for the heat storage is optimal for this type of system.



a)



b)

Figure 6 Impact of the heat demand. The gray area corresponds to a 5% margin of the heat demand. During summer in order to reduce the imbalance the real heat delivered (blue line) touches the upper limit often.

5 Conclusion

In this work an optimization algorithm was designed to reduce the imbalance in a virtual power plant that consists of several micro-CHP systems and a PV installation.

The optimization algorithm employs a mixed integer linear model that decides the day-before the amount of electricity that is going to be produced and at real time using a rolling horizon approach reschedules the operation of the CHP in order to compensate for the imbalance.

The results show that using the rescheduling algorithm a total imbalance can be decreased by more than 80% in winter and spring. However, the reduction is more moderate in summer.

It was also shown that reducing the imbalance leads to a total cost reduction that depends largely on the actual imbalance price. Only in summer, a small increase of the cost was noted since the imbalance reduction was not large enough to compensate the increase on the fuel cost.

Finally, the impact of the heat demand is analyzed; it was found that a low heat demand characteristic of the summer months limits largely the capacity of the CHP to reduce the total imbalance. This is very critical since in summer the largest solar irradiation is expected.

The cost increase in summer opens the question for further research since it implies that using the rescheduling algorithm is not always profitable for the VPP. Further work will aim to minimize the total cost at every time step trying to obtain a good prediction on the imbalance prices and compare both approaches (i.e., physical imbalance reduction and total cost reduction).

6 Acknowledgment

The authors would like to thank the members of the IEA Annex 54, Mr. Steck (FFE, Germany) for his active cooperation and interesting discussions

The research of the first two authors has been supported by the research project ‘local intelligent networks and energy active regions’ (LINEAR) financed by the Flemish agency for innovation through science and technology (IWT).

7 references

[1] R. A. C. Van der Veen and L. J. De Vries, “The impact of microgeneration upon the Dutch balancing market,” *Energy Policy*, vol. 37, no. 7, pp. 2788–2797, Jul. 2009.

[2] M.Steck, “Simulation to quantify the revenues of linked chp-devices providing balance power under realistic conditions,” *Microgen II conference, Glasgow, Scotland*, 2010.

[3] T. Coppens, “Flexible cooling demand in Virtual Power Plants,” University of Leuven, Master thesis, 2012.

[4] M. Zdrilic, H. Pandzic, and I. Kuzle, “The mixed-integer linear optimization model of virtual power plant operation,” *8th International Conference on the European Energy Market (EEM), 2011*. pp. 467–471, 2011.

[5] R. D’hulst, K. Kessels, and D. Six, “Business case assessment of balancing large scale PV with flexible CHP,” *8th International Conference on the European Energy Market (EEM), 2011*. pp. 288–293, 2011.

[6] E. D. Mehleri, H. Sarimveis, L. G. Papageorgiou, and N. C. Markatos, “Model Predictive Control of distributed energy resources,” *20th Mediterranean Conference on Control & Automation (MED)*, *2012* pp. 672–678, 2012.

[7] K. Voorspools and W. Dhaeseleer, “Reinventing hot water? Towards optimal sizing and management of cogeneration: A case study for Belgium,” *Applied Thermal Engineering*, vol. 26, no. 16, pp. 1972–1981, Nov. 2006.

[8] W. D. J. Zapata Riveros, J. Vandewalle, “Assessment of different distributed generation technologies for a virtual power plant,” *IAEE European Energy Conference 2012*, no. Venice, 2012.

[9] C. Roselli, M. Sasso, S. Sibilio, and P. Tzscheutschler, “Experimental analysis of microcogenerators based on different prime movers,” *Energy and Buildings*, vol. 43, no. 4, pp. 796–804, Apr. 2011.

[10] D. Haeseldonckx, L. Peeters, L. Helsen, and W. D’haeseleer, “The impact of thermal storage on the operational behaviour of residential CHP facilities and the overall CO2 emissions,” *Renewable and Sustainable Energy Reviews*, vol. 11, no. 6, pp. 1227–1243, Aug. 2007.

[11] F. Geth, S. Member, J. Tant, and E. Haesen, “Integration of Energy Storage in Distribution Grids,” no. 1, pp. 1–6.

[12]“Elia,” *www.elia.be*, 2012. [Accessed october 2012] .